**DRAFT**

# Joint BPA and Northwest Gas Association Study of Pipes and Wires

## Executive Summary


Bonneville Power Administration (BPA) and the Northwest Gas Association (NGA) agreed to study the economics of delivering energy to load centers via electrical transmission lines versus natural gas pipelines. One objective was to determine which is more economically efficient. A second objective was to determine whether the Federal Energy Regulatory Commission's (FERC) pricing rules could create outcomes that do not comport with economic efficiency; in other words, whether FERC's policies tend to tilt the playing field toward a less than optimal economic outcome.

The Work Group compared the economic costs, reliability, delivery efficiency (energy losses), and other factors associated with energy delivery to a generator located near a load center via a 100-mile natural gas pipeline versus from an electric generator located near a gas pipeline delivering energy to a load center via a 100-mile electrical transmission line.

A key finding was that making valid comparisons between pipes and wires is complicated by the differing physics of the two systems. Natural gas pipelines are arterial in nature, and therefore tend to have more localized effects as a result of capacity expansions. Electric power grids, on the other hand, are highly interconnected and redundant.

Both pipelines and electric grid expansions are capital intensive. At the most basic level—capital cost per mile of each alternative—natural gas pipelines average between half and 60% of the cost of electric power transmission per unit of energy (or capacity) delivered. This implies that in many circumstances, a gas pipeline would be more economic than an electric transmission line. But because the physics, the associated benefits, and the availability of either adjacent pipelines or electrical interconnections are so case- and site-specific, it is not possible to conclude that one delivery system is preferable to the other.

The Work Group examined several facets of both the generic economics of pipes and wires as well as how those costs are recovered. Principal among those considerations were: 1) Who finances the project? 2) Who pays for the project?, 3) Are costs rolled in or paid incrementally?

FERC's pricing policies and case law appear to recognize the differences between the two systems and to have consistent (although still evolving) principles regarding pricing and cost-recovery for capacity expansions. We believe that the result is consistent treatment of natural gas pipelines and electric power transmission grids.

For example, one principle FERC consistently applies is that if the benefits accrue solely to one party, that party should pay the full cost of a capacity expansion, in addition to whatever other costs it must pay to obtain service. In fact, for the case we studied, and probably for most cases, a natural gas pipeline expansion is more likely to benefit an identifiable party than an expansion of the electric grid. So, the pricing constructs of the two alternatives differ; one is incremental, the other is rolled in. However, if the case we studied were viewed instead as a generation interconnection the two cases would be identical; the generator would pay the incremental costs in either case.

However, finding consistency in pricing principles is one thing; assuming that the merchant transmission model used in the natural gas pipeline industry will transfer to the electric industry is quite another. Our findings cast doubt on the prospects of FERC's vision of merchant electric transmission springing up to alleviate network congestion coming to fruition in the Pacific Northwest.

Finally, we conclude that, the benefits and costs of both systems may vary widely depending on site-specific circumstances. Both systems now are planned and developed separately. We recommend that, whenever possible, energy planning and development should incorporate both electrical and natural gas systems to optimize an integrated system, thereby providing the greatest benefits for society.

## Joint BPA and Northwest Gas Association Study of Pipes and Wires

Bonneville Power Administration (BPA) and the Northwest Gas Association (NGA) agreed to study the economics of delivering energy to load centers via electrical transmission lines versus natural gas pipelines. One objective was to determine which is more economically efficient. A second objective was to determine whether the Federal Energy Regulatory Commission's (FERC) pricing rules could create outcomes that do not comport with economic efficiency; in other words, whether FERC's policies tend to tilt the playing field toward a less than optimal economic outcome.

Specifically, the Work Group compared the economic costs, reliability, delivery efficiency (energy losses), and other factors associated with energy delivery to a generator located near a load center via a 100-mile natural gas pipeline versus from a generator located near a gas pipeline delivering electrical energy to a load center via a 100-mile electric transmission line.

Staff from BPA's Transmission Business Line and from several of the companies who belong to the NGA began this study in August, 2002. (See Appendix 1 for list of participants.) This paper describes the Work Group's study efforts and findings.

<u>Methodology</u>

During the course of designing a study approach, it quickly became apparent that most pertinent details about the economics of wires and pipelines are site and case specific. Nevertheless, the study was intended to answer general questions, not to study alternatives for specific proposed pipelines or electrical transmission lines. Therefore, the study compares two generic alternatives.

The first alternative is to build the generator near the main pipeline and use electrical transmission lines to deliver the power to the load (via the distribution system.) This is shown in the top portion of Figure 1 entitled "Illustration of Pipes vs. Wires Comparison".

In the second alternative, gas-fired electrical generation is located adjacent to the load center and a natural gas pipeline moves gas from a main interstate pipeline to the generator. This alternative is depicted in the bottom portion of Figure 1

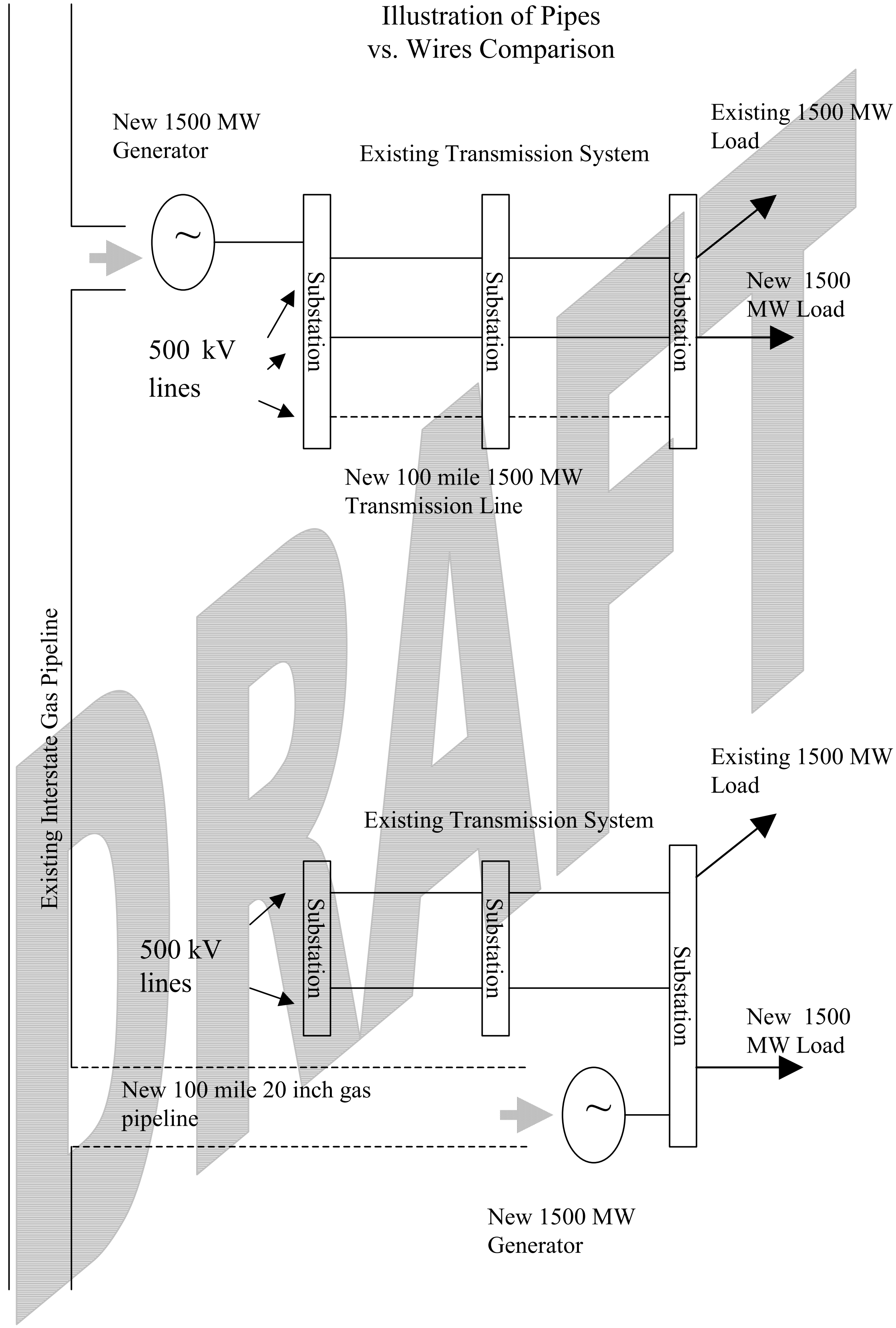
For purposes of analysis, we assumed that the distance to be covered in either scenario would be 100 miles; that is, we compared a pipeline to an electric transmission line, each 100 miles long.[1] We further assumed that the amount of power output from the generator would be 1500 MW. Work Group expertise was tapped to determine that: 1) a 20-inch

---

[1] Because nearly all costs are determined on a per-mile basis, this is not a critical assumption. There are no economies of scale for distance; i.e., costs are directly proportional to distance of the line.

Figure 1

Illustration of Pipes
vs. Wires Comparison



diameter pipe would be the optimal size of a pipe capable of delivering sufficient gas (250 million cubic feet of gas per day.[2] (mmcf/d)) to the plant; and 2) a 500 kV line would be sufficient to deliver the output of the 1500 MW plant to the load.

For analyzing costs, we considered varied terrain and ownership. While it is not possible to ensure that exactly the same assumptions are used by BPA for electric transmission and NGA companies for gas pipelines, we believe that the factors are sufficiently similar to afford reasonable comparisons for purposes of this study.

Pipeline estimates may not reflect the cost of all water crossings depending on the actual terrain being traversed. Significant water crossings would increase the cost of the pipeline somewhat but have little bearing on most electrical transmission line costs. The additional water crossings could add a few million dollars to the cost of the pipeline alternative, which is a small percentage increase.

While the cost accounting methods of the pipeline companies vary, for the purposes of this study, the companies agreed on a set of generic assumptions that generated representative annual costs for natural gas pipelines. BPA's cost accounting methods differ from those used by any of the pipeline companies. Just to cite two examples, BPA does not determine its cost of capital by a weighted average of debt and equity financing. Second, taxes, while obviously a cost to a project owner, are not generally factored into BPA's cost analyses, nor are they truly a social cost. However, trying to sort out the accounting was judged to be beyond the scope of the study. Instead, we determined that we would just compare capital costs and operating expenses. This can be justified because these costs are a fair representation of what society pays for such projects.[3]

Another simplifying assumption for purposes of analysis is that losses are ignored. We did calculate that about 20 MW would be lost over the 100 mile 500 kV line. However, as that represents less than 1.3% loss, it is ignored. Natural gas pipelines also use fuel for power compressor stations to maintain adequate pressure in the pipeline. This use is analogous to electrical losses and is of a similar magnitude. Therefore the two effects virtually cancel each other out.

Both transmission and pipelines are capital intensive. To test sensitivity, capital costs were spread over 30 years using various interest rates ranging from 7.0 percent to 12.0 percent. The 7.0 percent rate corresponds approximately to BPA's Treasury borrowing costs. The 12.0 percent rate corresponds closely to the average cost of capital in the private sector for these projects. Similarly, it is a rate close to what BPA has been quoted from customers who have expressed an interest in project financing. Because the

---

[2] This assumes a plant heat rate of approximately 7,000 Btu/kWh.

[3] As will be shown below, not only are the projects inherently not substitutable (meaning that an either/or comparison is a false one), the way the costs typically are recovered for pipelines differs from the way transmission costs are recovered.

pipeline companies who participated in this study have an average weighted cost of capital of 8.75 percent, results are shown for that, as well.[4]

The costs are shown in Table 1, Cost Comparison. The transmission costs are shown on the left, the pipeline costs on the right. The top three rows show, for each alternative, the capital costs per mile, capital costs per 100 miles, and the annual operations and maintenance (O&M) costs (or their equivalent.) The box below that displays the annual payment required to pay off the capital investment, both under 7.0 percent and 12.0 percent cost of capital. Next, the annual costs are computed, which are the sum of the annual capital payment and the annual O&M costs. Finally, those costs are spread over various units and displayed below. Specifically, values are shown for costs per kW-yr and per MWh under various load factors. BPA's current transmission rate is also shown for illustrative purposes.

Because these projects are so heavily capital intensive, one need not look much further than those costs to determine the relative ranking of the alternatives. The capital cost per mile of electrical transmission is nearly double that of pipelines. Therefore, all of the per unit costs of electrical transmission are nearly double those of pipelines.

The time period required to bring a natural gas pipeline project into service is typically 24 to 36 months, depending on the magnitude of the pipeline and compression additions as well as environmental, construction and terrain dynamics. This period allows for pre-certification activities including route studies, preliminary engineering and preparation of a FERC application. It also includes the FERC certification process including final approval of the project, ordering of pipeline and compression equipment and physical construction of the pipeline. It does not include the time required to get commercial arrangements in place to support the construction of the pipeline, otherwise known as the expansion open season process. This process can be as short as two weeks.

For high voltage electrical transmission lines, we assume that planning, which would include a version of "open season" would normally take a year. Environmental work could be as short as a few months, but would more likely take up to two years. Finally, design and construction would take an additional two years.

## Discussion

Several observations in light of the foregoing come to mind. First, this hypothetical transmission project is cheaper than current rates. In other words, the dollar per kW-year

[4] The costs shown here are economic costs for the purpose of comparing the amount of resources required to develop each alternative. It is not a rate analysis. That means that meaningful comparisons can be drawn among the alternatives concerning the overall cost that society would pay to develop either pipes or wires. However, a quite different analysis would be required to compute actual rates. As such, using these figures as proxies for rates or tolls would be misleading. Although BPA's transmission rate is shown for illustrative purposes, and although the costs shown would roughly approximate rate effects, the two are not strictly comparable.

cost of this project is less than what BPA currently charges customers for point-to-point transmission service. Thus, the project would meet the "or test"[5] and would be rolled into rates.

Second, when expressed on an energy basis, this shows how economic new transmission can be. Using a 65% load factor, which approximates the typical situation in the PNW, the fully allocated transmission costs are less than $2 per MWh. This implies that if the line were to reduce re-dispatch costs (or other congestion alleviating costs) by an average of more than $2/MWh, the line would pay for itself, at least from a societal point of view. (However, the incidence of specific customers' costs could differ in the case of re-dispatch compared to new transmission capacity.)

Finally, if it were true that one could simply build a transmission line or a pipeline *with everything else the same*, it is clear that pipelines would be more economic.

**Table 1 Cost Comparison**

**Transmission Costs**

| | | | |
|---|---|---|---|
| Capital cost per mile (new stations) | | $1,865,500 | |
| Capital Cost for 100 miles (new stations) | | | $186,550,000 |
| Operation and Maintenance Costs per year | | | $519,000 |
| *Annual Payment, 30 years* | | 1500 MW | *New Stations* |
| Miles | **7%** | | 12% |
| 100 | **$15,033,393.57** | | $23,158,999.32 |
| *O & M Costs* | **$519,000** | | $519,000 |
| *Total Costs per year* | **$15,552,394** | | $23,677,999 |
| ***Cost Per kW-Yr*** | **$10.37** | | **$15.79** |
| *BPA Transmission Rate* | **$12.16** | | $12.16 |
| *Cost per MWh (100% LF)* | **$1.18** | | $1.80 |
| *Cost per MWh (65% LF)* | **$1.82** | | $2.77 |

**Pipeline Costs**

| | | | |
|---|---|---|---|
| Capital cost per mile (new stations) | | $1,000,000 | |
| Capital Cost for 100 miles (new stations) | | | $100,000,000 |
| Operation and Maintenance Costs per year | | | $1,000,000 |
| *Annual Payment, 30 years* | | 1500 MW | *New Stations* |
| Miles | 7% | **8.75%** | 12% |
| 100 | $8,058,640.35 | **$9,518,589.85** | $12,414,365.76 |
| *O & M Costs* | $1,000,000 | **$1,000,000** | $1,000,000 |
| *Total Costs per year* | $9,058,640 | **$10,518,590** | $13,414,366 |
| ***Cost Per kW-Yr*** | **$6.04** | **$7.01** | **$8.94** |
| *BPA Transmission Rate* | $12.16 | **$12.16** | $12.16 |
| *Cost per MWh (100% LF)* | $0.69 | **$0.80** | $1.02 |
| *Cost per MWh (65% LF)* | $1.06 | **$1.23** | $1.57 |

* For purposes of this comparison, an annuity on the capital cost ("Annual Payment, 30 years") and "Total Costs per year" is computed. These figures are not necessarily representative of how natural gas pipelines or their customers would view the cost of transportation. As pipelines typically pass charges to customers through a transportation rate spanning the life of a facilities, annual cost of service, revenue requirement and the transportation rate are more representative measures of the customer's obligations.

Both pipelines and transmission lines are a means of transporting energy, sometimes over long distances. Further, both transport two of the significant energy resources in our economy. The resources are partially substitutable; either can be used to heat water or space, for example. But the differences are significant as well.

First, and probably most importantly, the physics of the systems differ. In an electrical system, everything is integrated—it is one large machine. Any disturbance, anywhere on the system, is "felt" everywhere else on the system, virtually instantaneously. Because of that, the system is planned and built on an integrated basis.

---

[5] The "or test" is discussed below.

One planning criterion unique to electrical systems is known as the N-1 criterion. Under this criterion, the system (including new system additions or capacity expansions) is planned such that if the worst possible contingency occurs, the system will still be able to deliver power to load. In other words, if the worst possible thing happens to the system--in the case at hand, the new line fails--the system can still meet load. No counterpart exists in the natural gas pipeline system.

The natural gas delivery system also is planned on an integrated basis, in that it takes into account what is there already, and recognizes options for complementary investments. Its system is arterial. It resembles, at least in some respects, the body's arterial system. Gas flows from large pipelines to ever-smaller ones, eventually ending at terminals or loads.

Second, Load Serving Entities (LSEs)[6] have gas storage and other backup solutions. In addition, the pipeline itself acts as a long storage tank. If inputs to the pipeline are shut off, users can still receive and use gas as long as sufficient pressure is maintained. Pipeline "outages" may be mitigated via storage. For the electrical system, the backup built into the network system mitigates transmission line outages.

Some of the differences between the arterial (gas) system and the network (electrical) are shown in Figure 1.[7] This is the case studied here. The top part shows the situation for an electric utility. Here the utility currently serves 1500 MW of load via two 500 kV transmission lines, each capable of carrying 1500 MW. To do so, it has two 500 kV lines already, under the reliability criterion that even if one line goes down, the load can still be served. Although the total capacity of the transmission lines in this example is 3000 MW, the reliable capacity of this two-line system is 1500 MW. Adding a third 500 kV line capable of carrying 1500 MW increases total reliable capacity to 3000 MW.

In the case of pipeline expansion, the situation differs. The bottom part of the figure shows the equivalent of a 1500 MW load (in this case represented by 250 mmcf/d of gas supply) served by a single pipeline. With an additional 250-mmcf/d load, one new pipeline will be needed to meet the expanded loads. In this case, if either pipeline shuts down, only a part of the load can be met, except to the extent storage is available at the load center to mitigate.

<u>Comparison of outage rates</u>

The electrical system is planned for single and credible double line outages (these are a single event that could take out two facilities). Lines typically experience 1.75 outages per year. They are involved in overlapping outages with another line 0.01 times per year.

---

[6] A more commonly used term in the natural gas industry is LDC, which stands for Local Distribution Company. Generically speaking, however, both gas and electric companies serve loads and therefore may be termed Load Serving Entities.

[7] This is a simplified view from both the electric and gas point of view. It is used only for illustrative purposes for the points in the text.

A single gas pipeline experiences 0.03 outages per year, which is comparable to the rate for double transmission line outages. Although pipelines experience fewer outages than transmission lines, the outages are often more catastrophic and the duration of these outages is typically much longer. Single line outages typically last 220 minutes while double line outages last 108 minutes. Although specific data on pipeline outages was not available, they are expected to last several days to weeks. This timeframe may be beyond the storage availability. Therefore, the overall reliability/availability of gas pipelines arguably is lower than the transmission system. (These statistics are from "Pipeline Statistics," Office of Pipeline Safety (U.S. Department of Transportation, Research and Special Programs Administration). http://ops.dot.gov/stats.htm)

If risks of line failures were equal, the electric network would provide superior reliability as compared to the gas arterial. However, failure risks are neither equal nor easily compared and, in both cases, are miniscule in probability. The consequences in any failure are situation-specific and depend on many factors well beyond the scope of this study.

<u>Pricing of Gas Pipelines and Electrical Transmission</u>

Not only are the physics and physical systems different, their pricing also differs, reflecting the nature of each system. This underscores the difficulty in comparing the cases at hand.

It is useful to review how transmission pricing has been done in the past, what we are doing today, and where FERC (and RTO West in a similar manner) appears to be heading in the future.

With regard to pricing there are several related concerns. Briefly, they are 1) Financing – Who provides the up front capital funding for the project? 2) Funding – Who actually ends up paying for the project? 3) What costs are paid by current ratepayers? 4) What costs are paid solely by the benefiting party? Those issues are described in the following sections.

<u>Historical and Current Electric Transmission Pricing</u>

Until recently, BPA planned the system based on forecasts of load and resources. BPA, on behalf of its customers, undertook the transmission investments it determined were necessary to meet loads with a high degree of probability. Some transmission investments were not included in the network's costs. These included, for example, the interties and local delivery facilities. So, "network" refers to the high voltage grid in the PNW. Regardless of where on the network an investment was made it was financed by BPA and rolled into rates charged to all network customers. Because the network is interconnected, upgrades help to provide backup transmission and to maintain voltage throughout the system, so that all customers benefit from maintaining reliability. Since all customers benefit, all customers pay. FERC historically has been supportive of this kind of pricing for all electric utilities.

Today's world is different. Now there are a variety of customers—generators, LSEs, and marketers who buy and sell power and move it across the network. Under the Open Access Transmission Tariff (OATT) customers generally fall into two categories: Network customers (served under the Network (or NT) rate) and Point-to-Point customers (served under the PTP rate.) All customers pay for usage of the network depending either on their load (NT) or their reserved capacity (PTP).

BPA continues to make investments on behalf of its treaty and contractual obligations, including the expected load growth of its NT customers. This is a network reliability consideration. In the simplest terms, reliability projects are ranked by their ability to improve (or avoid degradations in) reliability. Alternatives are considered and ranked according to a variety of factors, including cost, to determine which prospective project returns the greatest economic benefit in addition to the reliability benefits.

When it comes to PTP customers, things are different. With the Open Access Same time Information System (OASIS), customers enter a queue to reserve capacity on the network. If it is available, they acquire it and pay the prevailing rate—the same rate (price) as all other transmission customers. This confers upon the customer a right to use that amount of capacity over a specific path (Point of Receipt (POR) to Point of Delivery (POD)) during the time period for which it is purchased. It also confers other rights, such as the right to change the path under certain circumstances.

If insufficient capacity is available to meet its request, the customer has the option of either dropping out of the queue, or financing studies regarding the cost of capacity expansion. Ultimately, the customer would face the decision to finance the costs of the capacity expansion needed to meet its request. BPA will not, on behalf of its other network customers, take the risk of new investments that are needed only to meet specific customer needs and not network customer needs in general. Because the investment would not be undertaken "but for" the requesting customer, that customer must come forth with the necessary financing.

The "but for test" is often confused with FERC's so called "or test." According to that test, FERC will allow a utility to charge its customer under these circumstances either the rolled in rate *or* the incremental cost, but not both. The "but for test" is about *who* finances the project [8]; the "or test" is about *how much* they pay.

In return for its financial investment, the customer receives a credit on its transmission usage. The credit is sufficient to repay the customer for its financial investment because the credit would be applied according to prevailing transmission costs. In other words, prevailing transmission rates are credited to the customer's account to repay its financial investment. In the case at hand, for example, the customer would invest $186 million (plus interest) to finance the new 100-mile capacity addition. At current rates of

[8] Or, more precisely, who takes the risk.

$12.16/kW-year, the customer's bill would be credited with that price times the amount of transmission acquired until such time as the principal and interest were repaid.

To the customer the investment becomes a sunk cost and transmission is then "free" for as long as it takes to repay the investment. Thus, there is a tangible economic reward to the customer for its investment. As we will see, this is similar to how pipelines are financed and funded.

Note that while the customer takes the risk by *financing* the project, it does not *fund* the project. The distinction is important and, as we will see, is just as important in the new world envisioned by FERC. Let's say the Hoozit Generation Company finances the $186 million project that is the subject of this report[9]. BPA puts the $186 million on its books, including interest charges, and adjusts its transmission rates accordingly. It then repays the investment (and investor, Hoozit) by crediting the principal and the interest against Hoozit's transmission usage. Once the investment has been repaid, Hoozit begins paying for subsequent transmission usage.

For the other network customers the situation would be no different, in principle (if not principal), had BPA borrowed the money from the treasury. The key difference in fact would be the different interest rates paid. Nevertheless, Hoozit has no more funded the project than the U.S. Treasury funds other projects. It has *financed* the project and will then be repaid, with interest.

In all cases, either for network upgrades for reliability or for generation (or load) additions, costs are rolled into network costs. Rates are set to recover costs and all customers pay the same base rates. Thus, the current and future ratepayers on the network always do the funding. The only exception would be if the "OR" test triggered—that is, if the incremental cost of providing the new service exceeded the average cost rate. In that case, the amount by which the incremental cost exceeded the average cost would be financed *and funded* by the new customer.

One more note before turning to FERC's future direction. How does Hoozit benefit by this? After all, it isn't really going to receive any money for its investment, just a credit against its transmission bill. Is it really a tangible economic benefit? The answer is yes, but its value is a matter of entrepreneurial decision-making. It is instructive to compare Hoozit's situation with other sellers. Some other sellers may have purchased long-term firm point-to-point transmission out of existing capacity. Like Hoozit, these sellers would view their transmission costs as "sunk," because they are required to pay for the transmission regardless of whether they use it. Other sellers may connect to the system without firm transmission rights and take the risk of using non-firm transmission as available. On average, at today's rates, "free" transmission means that Hoozit has about a $2/MWh advantage over these other sellers who to pay for transmission as they use it. These sellers would then avoid the $186 million investment, but would have to pay about $2/MWh for transmission, when transmission is available and it is economic for the

[9] Assume the "or test" does not trigger. That is the usual case.

sellers to run their generators. If transmission were not available at any time, the sellers that depend on nonfirm transmission could not sell the power from their generators.

Note that whether Hoozit sees the transmission investment as a sunk cost depends on when the decision is made. Prior to undertaking the project financing, the essential question Hoozit faces is whether paying up front for the new transmission capacity is worth it compared to facing the congestion costs and risks it would face were the capacity expansion not made. At that point, there is no sunk cost. However, once Hoozit undertakes the financial investment, it owns transmission rights that then look "free." Moreover, on the path in question, because Hoozit has done the financing, it faces no congestion costs, while any other party without firm rights would. So, as we go forward in time, the transmission appears to be free to the generator, even though at the time the initial investment (financing the 1500 MW capacity expansion) was made the future transmission service clearly was not free.

<u>The Future of Electric Transmission Pricing</u>

Predicting where FERC and RTO West will end up on pricing is a challenge we're not up to, but the general direction today is becoming clearer. We discuss this in terms of the FERC Standard Market Design (SMD) Notice of Proposed Rulemaking (NOPR) and related activities, because it is likely to be applicable to the PNW as well as the rest of the country in one form or another.

Today, all transmission customers pay for their use of the network. FERC proposes that in the future only LSEs would pay the embedded costs of the network. (By this, they mean the rolled in costs that we think of as today's transmission rates.) Generators, marketers, and others would not pay. However, all entities—LSEs, generators, and marketers—would be subject to the risks of congestion costs, primarily redispatch costs when transmission is congested.[10]

Under SMD, generators (and others) can hedge congestion cost risk by the acquisition of Congestion Revenue Rights (CRRs), or, in the case of RTO West, Catalogue Transmission Rights (CTRs). These can be acquired through existing rights, by auction, by purchase from another owner, or by funding the investment in transmission capacity expansion. Participant funding is envisioned by FERC to be the key to developing needed capacity expansions. This is more than participant financing, as is possible in today's world. The customer pays for the project and receives in return an amount of CRRs for some period. Regardless of how a customer acquires its CRRs, their value is as a hedge against congestion costs.

Today, Hoozit gets a financial credit worth about \$2/MWh over the life of its contract. Tomorrow, Hoozit gets CRRs as a hedge against congestion costs. Economically, there

[10] Other costs such as those equivalent to today's Transmission Scheduling charges applicable to all schedules may apply, but are not relevant to this analysis.

shouldn't be much difference, at least in principle. Both represent advance purchases of transmission services. In fact, differences may and probably will arise.

One obvious difference is that today Hoozit knows that other similarly situated generators will incur essentially the same level of transmission costs, either as up front payments for new construction with credits, take or pay transmission payments for long term firm transmission out of existing capacity, or pay as you go transmission payments for short term firm and nonfirm transmission. Tomorrow, Hoozit will face a choice between investing a known amount for a network expansion and receiving congestion hedges or facing an uncertain amount of congestion costs in the future. Hoozit will know the congestion costs it faces when it makes its investment, but it will not know what congestion costs it faces subsequently. In addition, its investment (that is, the enhanced transmission capacity) will have its own effects on other congestion costs on the network, some predictable, some not. On top of that, future capacity expansions (for load or generation) will further change the various congestion costs unpredictably. Therefore, the value of the CRRs, as compared to credits in today's world is more speculative.

That's not all. Once Hoozit's investment comes to fruition, the capacity of the network is increased and congestion on that path is reduced. Congestion on other paths (or at other nodes) may increase or decrease. Overall, however, it is likely that adding capacity at one location to reduce congestion will reduce net network congestion. Presumably the congestion costs of all parties, taken collectively, will decline, although there may be winners and losers. Thus, there are potentially two sources of free ridership. The first is on the path being upgraded. Others who use the path can profit from the reduced congestion charges. The second is from users of other paths (or nodes) whose congestion costs also are reduced.

This sets up a game of electric chicken. Although Hoozit may profit from funding the capacity expansion, others are likely to profit, as well. If Hoozit waits, someone else may make the investment and Hoozit could profit as a result. In the latter case, it wouldn't have CRRs, but it might not need them, or their value may be reduced as a result of lower congestion costs.

It is true that free riders could exist under today's system, for the same reasons. However, the difference is that today Hoozit would have a clear $2/MWh advantage over its competitors. That advantage could be greater under the SMD proposal, or less; but it is certainly more risky.

Another aspect of LSEs paying for the rolled in costs of the transmission system is that generators don't pay for the embedded costs of transmission. There is really no such thing as the "or test." If the generator determines that the avoided congestion costs are worth it, they finance and fund the capacity expansion, regardless of how that cost compares to average embedded costs.

Finally, FERC contemplates that regional state advisory boards would inform transmission providers when new generation capacity is required to meet resource adequacy standards as loads grow. This would be similar to today's network planning for reliability. These costs would be rolled into the transmission provider's company rates and passed along to all LSEs. This is viewed by FERC as a backstop. It believes that avoiding congestion costs will provide sufficient economic incentives to market participants to fund transmission capacity expansion.

Natural Gas Pipeline Funding and Pricing

FERC defines three types of pipeline projects: an expansion to provide additional service (such as the case that is the basis for this report), a project to improve service to existing customers (analogous to transmission upgrades for reliability), and a combination of the two. The Commission's policy is that no subsidies should occur; therefore, those who benefit must fund expansions for additional service. If benefits (outweighing costs) cannot be demonstrated, existing customers are to be held harmless by the expansion. Expansion shippers must be willing to purchase capacity at a rate that pays the full costs of the project. (See Appendix 2, Current FERC Expansion Rate Policy for Gas Pipelines for more detail.)

For the case at hand, this means that the shipper must pay two transportation costs. One is for the transportation along the main pipeline, shown on the left. The other is the cost of the new 20" pipeline to serve the plant. Those costs are additive; that is, the shipper pays for the embedded costs of the main system *and* for the incremental costs of the arterial system.[11] In other words, when expansion costs exceed existing rates, the shipper is charged the incremental cost. If expansion costs are less than existing rates, the shipper is charged the existing rate.

This differs from the situation for the electric power generator who pays the average, or embedded cost, only. Because in the electrical network all customers benefit from the capacity expansion, and all customers pay for it, the generator pays only the embedded cost rate.

Another difference from today's electric power transmission pricing construct for new capacity additions to accommodate new customers is that the shipper does not necessarily have to finance the project although it does have to fund the project. If the pipeline owner and the shipper agree to contract terms, the pipeline owner, perhaps using a variety of other agreements with shippers, undertakes the financing and funding for the project. The pipeline owner is repaid by the rates that are charged to the shipper(s.) No shippers elsewhere on the system will pay any of the costs of the capacity addition. It will be funded entirely by the shipper. This corresponds to financing, funding and paying for sole use facilities on the electric grid, but not to the hypothetical network expansion under review here.

[11] If, however, the pipeline expansion can be achieved by looping an existing line and the toll is less than the existing toll, the costs are rolled into existing rates. This would be similar to expansions of the electric grid for reliability purposes.

As stated previously, there is no perfect analogy or substitutability between a pipeline and a transmission line. The closest thing to an electric network would be the main trunks of the pipeline system. All gas must pass through these arterials. Branching pipelines, however, have a clearly defined physical point of delivery and may or may not interconnect with other pipelines.

Expansion shippers may or may not increase the capacity of an existing pipeline, analogous to expanding electrical network capacity. Generally, if that occurs, there would be at least some benefit to existing customers. Therefore, the beneficiaries of the expanded service may or may not have to pay an incremental cost. This would be the case that most closely resembles the hypothetical case at issue here.

Although this pipeline-pricing concept differs markedly from today's pricing for transmission capacity expansions, it appears to be consistent with the pricing proposed under FERC's SMD NOPR. Shippers who want to expand service must pay the major pipeline rate, regardless. It is a sunk cost in that respect. For economic decisions, that is equivalent to saying there is zero cost for future use. Electric power generators also would face zero cost transmission under the existing system. Only if generators desire to alleviate the costs of congestion do they incur additional costs for transmission capacity expansion, just as a shipper decides to incur additional costs for pipeline expansion to alleviate "congestion costs;" i.e., the cost of not being able to deliver gas to the purchaser.

## Conclusions

The physics and the resulting infrastructure of natural gas pipelines and electric power transmission lines differ significantly, complicating efforts to establish clear and consistent findings. However, the group found that:

1. The cost of delivering energy via gas pipelines is anywhere from 40% to 50% less than the cost of delivering an equivalent amount of energy via electrical transmission lines. The economic advantage of pipelines increases directly as distances increase. Clearly, for long distances—and 100 miles is reasonably long—pipelines are more economically efficient.

2. FERC pricing policies appear to be consistent across both pipelines and electric transmission lines. In both cases, existing consumers are protected against the costs of capacity expansions. If they benefit from the expansion they will pay some portion of the costs; if they don't benefit, they will pay nothing additional. However, it is not clear that merchant electrical transmission will be forthcoming as FERC envisions.

3. Electric and gas transmission systems are planned independently. Planning the energy system in a more integrated fashion could bring additional benefits to consumers. Generally, it will be cheaper to transport gas to load centers, but there

are many circumstances in which electrical transmission upgrades would be more economic.

Recommendations and Next Steps

As the region's energy needs continue to grow and change, consumers will benefit by integrated planning and development of the energy delivery system. Generally, gas pipelines will be cheaper than electric transmission lines, especially over long distances, but as we found, there are numerous instances where electric transmission is the best or even the only alternative.

Consistent with our findings, we do see plants locating near electric transmission lines and building pipe, but fewer cases of locating near pipelines and building electric transmission; for example, the Gray's Harbor Plant was located close to the grid and a pipeline spur was built from the I-5 corridor. However, because siting requirements may sometimes dominate decisions about plant locations we do not know how prevalent this effect is. As it was beyond the scope of the study, we have only anecdotal evidence on which to rely.

Furthermore, the group realizes that the natural gas pipeline industry and the electric transmission industry do not necessarily compete with one another. BPA owns and operates about three-fourths of the high voltage transmission grid in the Pacific Northwest. While BPA is a federal agency, from an economic point of view it looks like a consumer (ratepayer) owned entity. Obviously, those consumers would be better off by $80 million by avoiding the costs of a $180 million electric transmission line and taking on the costs of a $100 million pipeline.

*We recommend that an appropriate body develop a regional process to identify opportunities to optimize plant siting decisions, including partnering of electric transmission providers, natural gas pipeline owners, and prospective generators. The systems that transport energy are dynamic, both in real time and for system planners. Their optimum development and use lies not in either one, but in both systems working in concert.*

We examined FERC pricing policies for natural gas pipelines and for electric transmission lines and found them to be consistent. However, while merchant transmission is common and well developed in the pipeline industry, it is not in the electric transmission industry. It remains to be seen whether FERC's vision of network capacity being supplemented largely by merchant transmission will be fulfilled.

Our study looked at FERC's decisions and how utilities are required to finance and fund network expansions. We did not, however, examine actual cases of merchant transmission. On the electrical side, in the Pacific Northwest, there are practically none. The only notable exception is the transmission required for generation interconnection, which looks very much like merchant pipeline additions. However, that is far removed from merchant transmission on the electric grid, an unproven concept in the region.

As we noted, it is often the case that the direct beneficiaries of a pipeline addition can be identified. Because they have a property right with a clear economic value, financing requires rates of return somewhere in the 8 to 12 percent range, depending on debt and equity costs. In other words, it is a fairly low risk transaction.

Such is not the case for merchant electric transmission. Recall that merchant transmission in the future goes beyond financing the investment and being repaid with credits on one's bill. In the future, merchant electric transmission owners finance and fund the investment and receive Congestion Revenue Rights in return. The merchant transmission owner thereby acquires a property right, which is not clear, and has unknown economic value. It is easy to imagine that the required return on investment would be much higher than we observe with pipeline owners. Whether anyone will be willing to undertake such investments in the region is unknown.

Although RTO West, the proposed regional transmission organization for the Pacific Northwest, will have backstops to ensure a reliable electric network, we don't know when or even whether RTO West will actually come to fruition. Further, transmission owners will always be under FERC's jurisdiction or scrutiny, and FERC is solidly behind merchant transmission.

*We recommend further study of transmission merchants. It would be useful to know more about the characteristics of successful merchants, as well as those that create obstacles or disadvantages. Translating the natural gas merchant pipeline model to the electric grid will continue to bear close watch.*

Within the range of distances likely to be spanned in the Pacific Northwest, gas pipelines are likely to be cheaper for transporting large quantities of energy. However, we did not examine very long distances of more than a thousand miles. Over such a distance, the economics could change because Direct Current (DC) lines become more economic than conventional lines. No intervening substations are required as are with Alternating Current (AC) lines. In addition, losses are lower. Offsetting that, a converter station is required at each end and they are costly. In fact, their cost prevents DC lines from being economic for short distances.

Although DC lines are not likely for the regional transmission grid, TransCanada Pipelines, Ltd is exploring the possibility of building a DC line from Northern Alberta to the Mid-Columbia area. While that project is not to transmit electric power generated by natural gas, necessarily, it is not far-fetched to imagine another Canadian entity proposing to generate directly at the gas field and transmitting electric power via DC lines to the U.S. Northwest, or even California. Whether it would be economic to do so is unknown.

*We recommend that the same regional body consider long distance energy transport in its study and to report on its findings. We also caution readers of this report to limit our findings to the Pacific Northwest region.*

Appendix 1

Participants in BPA/NGA Study

| Participating Company | Representative |
| --- | --- |
| Bonneville Power Administration | Shep Buchanan<br>Marv Landauer<br>John Quinata<br>Len Morales |
| Northwest Gas Association (NGA) | Dan Kirschner |
| Supporting Members of NGA | |
| Avistacorp | Roger Woodworth |
| Cascade Natural Gas Corp. | King Oberg |
| Duke Energy | Elizabeth Moore |
| Northwest Natural | Randy Friedman |
| PG&E National Energy Group | Kevin Christie |
| Williams | Jan Caldwell |

## Appendix 2

## Current FERC Expansion Rate Policy for Gas Pipelines

The Commission's September 15, 1999 Policy Statement[12] on proposed gas projects established a no-subsidy policy favoring incremental pricing of pipeline expansions, thereby changing the Commission's previous policy of giving a presumption for rolled-in rate treatment for pipeline expansions. The Commission found that rolled-in pricing sends the wrong price signals by masking the true cost of capacity expansions to the shippers seeking the additional capacity.

In the Policy Statement, the Commission defined three different types of pipeline projects: an expansion project to provide additional service; a project to improve service to existing customers by replacing existing facilities, improving reliability, or providing additional flexibility; and a project that combines an expansion for new service with improvements for existing customers. Under the Commission's no-subsidy policy, existing shippers should not have the rates under their current contracts changed because the pipeline has built an expansion to provide service to new customers. Existing customers' rates can be increased for projects that improve their service. And, where a project combines an expansion with improvements to existing services, a pipeline can file to increase existing customers' rates when the pipeline can demonstrate that the new facilities are needed to improve service to existing customers.

In order to demonstrate to the Commission whether the market finds an expansion project economically viable, expansion shippers must be willing to purchase capacity at a rate that pays the full costs of the project, without subsidy from existing shippers through rolled-in pricing. The Commission indicated that removal of the subsidy is necessary to ensure that the market finds the project is viable because either the pipeline or its expansion shippers are willing to fully fund the project. In addition, the no-subsidy requirement is also needed to ensure existing pipelines do not receive unfair advantage in competition for new construction projects with new entrant pipelines.

In the case of inexpensive expandability that is made possible because of earlier, costly construction, existing customers could be disadvantaged because incremental pricing could result in the new customers receiving a subsidy from existing customers because the new customers would not face the full cost of the construction that makes their new service possible. The Commission indicated that the issue of the rate treatment for such cheap expandability is one that always should be resolved in advance, before the construction of the pipeline. Typically, pipelines file to apply current system rates for the expansion and agree to address rate issues in the pipelines next rate case.

[12] Citing Certification of New Interstate Natural Gas Pipeline Facilities (Policy Statement), 88 FERC ¶ 61,227 (1999), clarification, 90 FERC ¶ 61,128 (2000), further clarification, 92 FERC ¶ 61,096 (2000).